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9 February 2009

## VIA HAND DELIVERY

Mr. Bruce H. Burcat  
Executive Director  
Delaware Public Service Commission  
861 Silver Lake Blvd., Ste. 100  
Dover, DE 19904

Re: *PSC Docket No. 08-266F*

Dear Mr. Burcat:

Enclosed please find the original and ten (10) copies of the Direct Testimony of Staff Witnesses Richard W. LeLash and Courtney Stewart in the above-captioned docket. Copies have been provided to the service list in the manner indicated.

Respectfully submitted,

James McC. Geddes

Enclosures  
JMcCG:dlb

cc: Hon. Mark Lawrence (via e-mail & hand delivery; w/encls.)  
Courtney Stewart (via e-mail & hand delivery; w/encls.)  
G. Arthur Padmore (via e-mail & hand delivery; w/encls.)  
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Edward Taylor (via e-mail & U.S. mail; w/encls.)

BEFORE THE PUBLIC SERVICE COMMISSION  
OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION OF )  
DELMARVA POWER & LIGHT COMPANY FOR ) PSC Docket No.08-266F  
APPROVAL OF MODIFICATIONS TO ITS )  
GAS COST RATES. )  
(FILED August 29, 2008) )

DIRECT TESTIMONY

OF

RICHARD W. LELASH

ON BEHALF OF

COMMISSION STAFF

February 9, 2009

DELMARVA POWER & LIGHT COMPANY  
DOCKET NO. 08-266F  
TESTIMONY OF RICHARD W. LELASH

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1 I. STATEMENT OF QUALIFICATIONS

2  
3 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE  
4 RECORD.

5 A. My name is Richard W. LeLash and my business address is 18 Seventy Acre  
6 Road, Redding, Connecticut.

7  
8 Q. WHAT IS YOUR CURRENT BUSINESS AFFILIATION?

9 A. I am an independent financial and regulatory consultant working on behalf of  
10 several state public utility commissions and consumer advocates.

11  
12 Q. PRIOR TO YOUR WORK AS AN INDEPENDENT CONSULTANT, WHAT  
13 WAS YOUR BUSINESS AFFILIATION, AND WHAT WAS YOUR  
14 REGULATORY EXPERIENCE?

15 A. I was a principal with the Georgetown Consulting Group for twenty years. During  
16 my affiliation with Georgetown, and continuing to date, I testified on cost of  
17 service, rate of return, and regulatory policy issues in about 300 regulatory  
18 proceedings. These testimonies were presented before the Philadelphia Gas  
19 Commission, the Federal Energy Regulatory Commission and in the following  
20 jurisdictions: Alabama, Arizona, Colorado, Delaware, District of Columbia,

1 Georgia, Illinois, Kansas, Maine, Maryland, Minnesota, Missouri, New Jersey,  
2 New Mexico, New York, Ohio, Oklahoma, Pennsylvania, Rhode Island,  
3 U.S. Virgin Islands, and Vermont.  
4

5 Q. MR. LELASH, WHAT IS YOUR EDUCATIONAL BACKGROUND?

6 A. I graduated in 1967 from the Wharton School with a BS in Economics and in 1969  
7 from the Wharton Graduate School with an MBA.  
8

9 Q. DURING THE COURSE OF YOUR REGULATORY WORK, WHAT HAS  
10 BEEN YOUR EXPERIENCE WITH GAS POLICY AND PROCUREMENT?

11 A. Since 1980, I have worked extensively on gas policy and procurement issues. In  
12 my Appendix there is a listing of the recent cases in which I have sponsored  
13 testimony. In addition to these cases, I have reviewed and analyzed many other  
14 gas policy filings which were resolved through stipulation. Among other issues,  
15 my testimonies have involved gas service unbundling, physical and economic  
16 bypass, gas supply incentives, gas plant remediation costs, gas price hedging,  
17 demand and capacity planning, gas storage options, gas price forecasting, and least  
18 cost gas standards. In addressing these issues, I have analyzed gas regulatory  
19 filings involving about 30 different local distribution companies.

1 II. SCOPE AND PURPOSE OF TESTIMONY

2  
3 Q. WOULD YOU PLEASE STATE THE SCOPE AND PURPOSE OF YOUR  
4 TESTIMONY IN THIS PROCEEDING?

5 A. I was hired by the Staff of the Public Service Commission ("Commission") to  
6 review the Gas Cost Rate ("GCR") application made by Delmarva Power & Light  
7 Company ("Delmarva" or "Company") and evaluate its procurement against  
8 established regulatory standards. My review focused on the gas costs, gas  
9 purchasing practices, and the management of the Company's gas supply.

10 The purpose of my testimony is to present findings and recommendations  
11 to the Commission concerning issues raised by the application and the Company's  
12 on-going gas procurement policy and practices.

13  
14 Q. IN PERFORMING YOUR REVIEW AND ANALYSIS, WHAT DATA  
15 SOURCES DID YOU UTILIZE?

16 A. My review and analysis encompassed the Company's application, responses to  
17 discovery requests, and information provided during informal discovery. I also  
18 utilized information provided in other Company proceedings before the  
19 Commission.

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1

2 Q. WAS THIS TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT  
3 SUPERVISION?

4 A. Yes, this testimony was prepared by me.

1    III.    ISSUES OVERVIEW AND FINDINGS

2  
3            -            Delmarva's Procurement

4  
5    Q.    WOULD YOU PLEASE DISCUSS THE COMPANY'S PROCUREMENT IN  
6           GENERAL TERMS?

7    A.    At the current time, the Company's GCR rates and its procurement practices are  
8           being affected by several major external factors. Several of these factors, such as  
9           high natural gas commodity prices, gas price volatility, and demand changes  
10          related to price elasticity and conservation, all have had, and will continue to have,  
11          an impact on the Company's GCR prices. From an operating perspective, the  
12          characteristics of the Company's service territory, limited incremental capacity  
13          offerings, and the Company's operation of its LNG facilities all place demands or  
14          constraints on Delmarva's procurement process.

15  
16    Q.    WOULD YOU BRIEFLY DISCUSS SOME OF THE EXTERNAL FACTORS  
17           THAT YOU REFERENCE?

18    A.    The range of recent natural gas commodity prices can be seen in the Henry Hub  
19           rates shown on Schedule 1. Two periods of high prices during the September  
20           through December 2005 and April through July 2008 periods had prices that

1 averaged \$11.80 per Dth. This is in contrast to current gas price estimates for  
2 2009 which average \$4.23 per Dth.

3 Such gas price volatility brings into question how gas utilities should  
4 manage their commodity gas procurement. During the past ten years average gas  
5 prices increased from about \$2.00 per Dth up to about \$8.00 per Dth (a 300%  
6 increase). Under such conditions, it is not surprising that hedged positions, for the  
7 most part, had lower average costs than those of index positions. However, it is  
8 unlikely that there will be another 300% increase over the next several years.

9 Accordingly, it may be appropriate for gas utilities to re-evaluate their hedging  
10 programs to not solely orient toward addressing gas prices increases. With the  
11 more recent trends in gas costs and evidence of increased speculative trading, gas  
12 utilities' hedging programs may need refinement and potentially the adoption of  
13 different approaches for setting hedging programs' parameters.

14 In developing any prospective hedging program it is important that utilities  
15 such as Delmarva recognize that gas price risk has two dimensions. The first  
16 involves the risk that market prices may move up when gas purchases are  
17 unhedged. The second involves the risk that market prices may fall when gas  
18 positions are hedged. Accordingly, hedging programs for regulated gas utilities  
19 need to address both aspects of price risk.

1           A second external factor involves a greater need to ensure supply  
2 reliability. Hurricanes Katrina, Rita, and Ike have shown the vulnerability of Gulf  
3 of Mexico supply and infrastructure. In addition, shallow water Gulf and Gulf  
4 coast on-shore gas production as well as foreign LNG supplies have been in  
5 decline. As a result, gas utilities have been evaluating non-gulf based supplies and  
6 market area rather than production area storage. This in turn has shifted utilities'  
7 interest to production from the Rockies, the Rockies Express ("REX") pipeline  
8 and associated pipeline expansions and storage projects located in Ohio,  
9 Pennsylvania and New York.

10           Delmarva's recent acquisition of 25,000 Dth per day of Transco's Sentinel  
11 FT capacity was in keeping with this trend of gas supply diversification. Had  
12 Eastern Shore's E3 project gone forward as planned, it also would have diversified  
13 the Company's gas supplies and added to overall system reliability.

14           A third external factor that has a bearing on Delmarva's gas procurement  
15 involves ongoing customer demand. There has been a declining trend in gas usage  
16 per customer associated with housing weatherization and increased efficiency in  
17 gas-fired equipment. This trend, along with the impact of price elasticity and  
18 conservation initiatives, has slowed gas demand at least in the residential sector.  
19 Likewise, the current housing market, and the overall economy are also slowing  
20 gas demand at least in the short-term. Add uncertainties concerning global

1 warming effects, gas-fired electric generation, and alternative energy sources and  
2 the demand uncertainties affecting natural gas usage are apparent.

3 Based on these various factors, it can be seen that gas procurement has  
4 become increasingly complex. Accordingly, demand forecasting, capacity  
5 planning and management, gas price hedging, and even the use of utilities' LNG  
6 and LPG resources require additional examination and potential modification to  
7 current practices.

8 .  
9 - Summary of Findings and Recommendations

10  
11 Q. WOULD YOU PLEASE SUMMARIZE YOUR FINDINGS AND  
12 RECOMMENDATIONS CONCERNING THE COMPANY'S GCR FILING?

13 A. Based upon my review and analysis, the following are my major findings and  
14 recommendations:

- 15  
16 1. While the Company's design day HDD criterion may be somewhat  
17 conservative (overstated), its regression analysis is comprehensive and  
18 produces design day demand requirements that are reasonable.  
19

LeLash/Direct

2. With the addition of 25,000 Dth of daily deliverability from its new Transco Sentinel FT, the Company has a 9% capacity reserve. If one assumes that the Company's LNG facility can deliver an incremental 20,000 Dth of daily deliverability, that increases the capacity reserve to 20%
3. There are indications that the Company may not always be using its full storage entitlements. Prospectively, the Company should ensure that its storages are as close to full as is operationally feasible at the start of the peak winter season. Such full storage use will enhance gas supply reliability and potentially allow more off-system sales and capacity releases.
4. The current sharing formula for off-system sales and capacity releases does not represent a reasonable incentive for the Company. The \$1.7 million threshold is outdated, and the payment to the Company is not linked to performance.
5. It is recommended that the threshold be increased to \$4.4 million which represents 75% of the Company's average historical margin level. Such a

1 framework with the Company receiving 20% of margins in excess of the  
2 higher benchmark will provide a fair and adequate incentive for better than  
3 average performance.

- 4
- 5 6. The Company's current gas price hedging program should be reevaluated  
6 and modified as required. Based on current gas price trends, the level of  
7 hedging is excessive and speculative. Results over the last three years have  
8 been very poor in comparison to the hedging results for other gas utilities.  
9 Changes should be considered for the type of hedging being done, its scope,  
10 and its overall objectives.

- 11
- 12 7. It is recommended that the Commission require a reevaluation of the  
13 hedging program with the Company submitting a comprehensive report to  
14 the Commission or, alternatively, that some form of collaborative process  
15 be initiated so that the program can be altered as required within six  
16 months.

- 17
- 18 8. It is recommended that the Company submit its Gas Hedging Quarterly  
19 Reports and other related Company hedge analyses within 30 days of the

1 end of each quarter. Such filings and deadlines will allow the parties to  
2 monitor hedging on a more timely and comprehensive basis.

3  
4 9. The Company incurred a \$68,150 pipeline penalty associated with  
5 overtaking 3,326 Dth of FSS supply. Given the nature of the overtake and  
6 the Company's more than adequate daily deliverability, the penalty should  
7 be assessed to transportation customers and/or the Company.

8  
9 10. While the Company has evaluated the use of a third party for capacity  
10 optimization, it has never specifically determined the economic impact of  
11 utilizing an asset manger. Accordingly, the Company should contact  
12 various asset managers and, if there were sufficient interest from the asset  
13 managers, the Company should solicit bids to determine what terms and  
14 conditions could be obtained.

1 IV. GCR AND PROCUREMENT ISSUES

2  
3 - Forecasting of Demand Requirements

4  
5 Q. AS A GENERAL MATTER, HOW DO GAS UTILITIES DETERMINE THEIR  
6 SYSTEM GAS REQUIREMENTS?

7 A. Gas utilities evaluate their annual, winter season, and design day requirements by  
8 analyzing their historical experience and by making forecasts of their expected  
9 customer growth. The resultant analysis seeks to determine their necessary levels  
10 of gas supply to ensure system reliability. For Delmarva, and for most gas  
11 utilities, the critical metric is their design day requirements because they dictate  
12 the level of transportation, storage, and peaking supply that must be available to  
13 meet the demand on the coldest winter day when requirements are at their highest.

14 As part of the design day analysis, there are four key considerations. The  
15 first involves the appropriate level of heating degree days (HDDs) that could be  
16 experienced. The second part is to forecast firm sendout requirements associated  
17 with a design day HDD level. The third is to adjust the sendout requirements for  
18 expected customer growth, and the fourth involves an assessment of potential  
19 changes in the level of customer usage over time.  
20

1 Q. WOULD YOU BEGIN BY DISCUSSING THE PROCESS OF DETERMINING  
2 AN APPROPRIATE HDD LEVEL?

3 A. Prior to the various studies concerning global warming, there was a consensus that  
4 historical temperatures (and HDDs) were reflective of future temperatures. As  
5 such, by looking at the past twenty or thirty years of history, one could reasonably  
6 determine what would be the coldest day and the highest HDD for the future. On  
7 that basis, one could adopt an HDD level with a one-in-twenty or a one-in-thirty  
8 year chance of occurrence.

9 For Delmarva, the coldest day in the last thirty years occurred on January  
10 21, 1985 when the HDD level was 67. On a one-in-twenty year basis, the coldest  
11 day was January 19, 1994 with 62 HDD (Company Response PSC-96). For  
12 comparison, during the past five winter periods the range for the coldest day has  
13 been between 43 and 52 HDD (Company response DPA-25). All of this data is  
14 based on the average mean temperature.

15 Based on this data, the Company's use of a design day criterion of 65 HDD  
16 approximates the average of its one-in-thirty and one-in-twenty coldest day. As  
17 such, the Company's definition of its coldest day is compatible with the  
18 methodologies employed by other gas utilities. Unfortunately, in the Company's  
19 2008 Strategic Gas Supply Plan, it states that its design day forecast is based on an  
20 average effective temperature of 65 HDD. This statement appears to be incorrect

1 since the details of its regression analysis show the use of actual mean rather than  
2 effective temperatures.

3  
4 Q. ONCE THE DESIGN DAY HDD CRITERION IS DETERMINED, HOW DOES  
5 THE COMPANY TRANSLATE THAT INTO ITS FORECASTED DESIGN  
6 DAY SENDOUT REQUIREMENT?

7 A. The typical procedure is for the gas utility to develop regression analyses that, in  
8 their simplest form, compare the relationship between daily firm sendout and  
9 HDD levels. This is done by plotting actual daily data for sendout and HDD over  
10 an appropriate time period. Then statistically a least squares line is calculated  
11 from the data to quantify the relationship of the two variables.

12 In the Company's analyses, data from October 1, 2007 through March 31,  
13 2008 was utilized and 14 regressions were developed using various assumptions.  
14 The regression with the highest regression coefficient confirms the Company's  
15 derived design day demand forecast of 176,000 Mcf on a day with 65 HDD  
16 temperature. Additionally, this 2007-2008 forecast was then adjusted for customer  
17 growth to derive a 2008-2009 forecast of 178,169 Mcf (Response PSC-51).

1 Q. IN YOUR OPINION, IS THE METHODOLOGY USED BY THE COMPANY A  
2 REASONABLE FORECAST OF DESIGN DAY FIRM DEMAND?

3 A. Yes, it is. The regression analysis had a regression coefficient of 0.9859 which  
4 shows a high correlation between the HDD level and the resultant firm sendout.  
5 The only associated issue involves the Company's use of a one-in-thirty year  
6 HDD. If one believes that there is a global warming trend, then such a historical  
7 HDD level may overstate the HDD level that is assumed and in turn this would  
8 overstate the sendout requirements. However, given the current practice in the  
9 industry to use either a one-in-thirty or one-in-twenty benchmark, the Company's  
10 65 HDD appears reasonable.

11  
12 - Capacity Planning and LNG  
13

14 Q. WOULD YOU NOW DISCUSS HOW THE DESIGN DAY SENDOUT  
15 FORECAST IS USED TO DETERMINE A GAS UTILITY'S REQUIRED  
16 DAILY DELIVERABILITY CAPACITY?

17 A. On Schedule 2, there is data which shows the Company's available capacity and  
18 its daily deliverability in comparison to the derived design day demand  
19 requirement. As the schedule shows, the Company currently has daily  
20 deliverability of 193,385 Mcf, which represents about 109% of its indicated design

1 day requirement. For most gas utilities, the maximum capacity reserve is about  
2 5%, which typically will be able to cover two or three years of growth in design  
3 day capacity requirements associated with customer growth. For Delmarva, as  
4 shown in its Strategic Gas Supply Plan, its current deliverability is sufficient to  
5 maintain a 5% reserve through 2011-2012 even with its expected customer  
6 growth.

7  
8 Q. ARE THERE OTHER ASPECTS OF THE COMPANY'S CAPACITY LEVEL  
9 THAT SHOULD BE CONSIDERED?

10 A. Yes, the level of deliverability from the Company's LNG facility is also a  
11 potential issue. As stated in its supply plan, the maximum planned volume  
12 available from vaporization is 25,000 Mcf, but the Company can, under  
13 emergency conditions, produce up to 45,000 Mcf (2008 Strategic Supply Plan,  
14 page 16). Assuming that a one-in-thirty year event represents an emergency  
15 condition, it is unclear why the LNG deliverability is not planned at 45,000 Mcf  
16 for a design day. As shown on the first page of Schedule 2, with such a level of  
17 supply, the Company's reserve margin increases from 9% up to 20%. Including  
18 45,000 Mcf of LNG shows the capacity reserve to be 13% in 2013-2014.

19 This LNG deliverability is not an academic issue, since ratepayers pay for  
20 incremental capacity as well as for the LNG facility. While it may be within the

1 Company's business judgment to maintain a 5% reserve, a reserve of 20% is not  
2 cost effective. Planning LNG at 25,000 Mcf when its full capacity is 50,000 Mcf  
3 does not appear either realistic or practical.

4  
5 Q. BASED ON THE CURRENT CAPACITY RESERVE AND THE POTENTIAL  
6 ADDITIONAL 20,000 MCF OF SUPPLY FROM THE COMPANY'S LNG,  
7 WHAT ACTIONS SHOULD BE TAKEN BY THE COMMISSION?

8 A. At the present time, with the Company having already committed to 25,000 Dth of  
9 Sentinel capacity, there appear to be few options available. However, a first step  
10 would be for the Company to reevaluate its LNG deliverability and provide the  
11 Commission with a definitive determination of what level of capacity should be  
12 assumed for meeting a design day. If it is determined that the level is in excess of  
13 25,000 Mcf per day, then the Company should further evaluate whether some  
14 other capacity could be turned back or at least used for off-system sales or release  
15 on either a short or long term basis.

16  
17 Q. DURING THE PAST SEVERAL YEARS, HOW HAVE THE COMPANY'S  
18 CAPACITY COSTS INCREASED?

19 A. Page 2 of Schedule 2 provides data on the levels of customers and fixed capacity  
20 costs over the past five years. As the data shows, both RSH and total customers

1 grew at about 1 to 1-1/2% during the 2003 to 2007 period, but their growth  
2 declined last year. Given current economic conditions, it is expected that the low  
3 customer growth level will continue for potentially the next two or three years.

4 In contrast, fixed capacity costs that declined between 2003 and 2006 are  
5 now increasing at more than 10% per year. Such increases relate to rate increases  
6 and the addition of the Transco Sentinel FT capacity. Together, the lower  
7 customer growth rate and the increased fixed capacity cost highlight the need to  
8 limit capacity when it is not truly needed and to maximize capacity margins and  
9 credits when possible.

10  
11 Q. ARE THERE ANY OTHER CONSIDERATIONS ASSOCIATED WITH THE  
12 COMPANY'S CURRENT LEVEL OF CAPACITY?

13 A. Yes. Since ratepayers bear the costs of all capacity, there are questions concerning  
14 whether the Company should benefit from having more capacity than necessary.  
15 Unfortunately, the current margin sharing framework provides the Company with  
16 an inherent benefit if it maintains excess capacity. This issue will be discussed  
17 further in a later section dealing with off-system and capacity release margin  
18 sharing.

1 Q. ARE THERE ANY OTHER CAPACITY RELATED ISSUES THAT YOU  
2 EVALUATED?

3 A. Yes. As part of my review, an analysis was done on the Company's utilization of  
4 its gas storage capacity. As a general matter, gas utilities inject gas into storage  
5 during the April through October timeframe and withdraw it during the peak  
6 season of November through March. On Schedule 3 data is presented that shows  
7 the highest inventory levels for each of the Company's major storages over the last  
8 five years and the maximum storage fill in the October to November period.

9 In the majority of cases, storages were brought close to capacity.  
10 However, in 2007 and 2008 the Company had its ESS storage at the highest level  
11 (100%), while during 2004-2006 the storage was only at 43% by November. The  
12 ratepayers pay the demand cost for these storages, and it is only logical that the  
13 storage capacity be fully utilized. As an example, the Company's own LNG  
14 storage capacity is in excess of 250,000 Dth, but the tank has often been 10%  
15 below this level.

16  
17 - Capacity Margin Sharing  
18

19 Q. WHAT HAVE BEEN THE COMPANY'S HISTORICAL LEVELS OF OFF-  
20 SYSTEM MARGINS AND CAPACITY RELEASE CREDITS?

1 A. The levels of margins and credits for the past seven GCR periods are shown on  
2 Schedule 4. It should be noted that the amounts for 2004-2005 and 2005-2006  
3 have been adjusted to restate the off-system margins for October and November  
4 2004.

5 On these margins and credits, the Company retains 20% of any total in  
6 excess of \$1.7 million. Thus, for the 2007-2008 period, the Company retained  
7 about \$1.2 million. In this context, it should be remembered that the Company has  
8 an obligation to provide least cost procurement and effective utilization of surplus  
9 capacity is one of the activities that is required to meet its obligation. Also, it  
10 should be remembered that ratepayers, and not the Company, pay all capacity  
11 related costs.

12  
13 Q. IN YOUR OPINION, IS DELMARVA'S CURRENT MARGIN SHARING  
14 REASONABLE?

15 A. No, it is not. Based on the prior seven years' experience, the current \$1.7 million  
16 margin threshold is outdated. As shown on Schedule 4 the Company's lowest  
17 level of shareable margins has been \$3.094 million during the past seven years,  
18 and the average margins have been \$5.8 million. Thus, if incentives are supposed  
19 to be linked to superior performance, margin levels below a reasonable threshold  
20 should not result in any sharing for the Company.

1  
2  
3  
4  
5  
6  
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8  
9  
10  
11  
12  
13  
14  
15  
16  
17

Q. WHAT ARE THE BASIC PRINCIPLES WHICH ARE APPLICABLE TO  
MARGIN SHARING INCENTIVES FOR A GAS UTILITY SUCH AS  
DELMARVA?

A. As a general matter, the incentive should apply to activities that the utility is not  
otherwise required to perform. Absent such a condition, the incentives could be  
designed symmetrically so that the utility would be penalized for poor  
performance to the same degree it is rewarded for better than average results. In  
addition, the incentive should not provide reward for results which are not directly  
related to Company performance and the incentive should not give rise to  
activities which are unintended or unreasonable, such as the acquisition of  
unneeded capacity.

Given the fact that natural gas distribution companies are required to pursue  
a least cost fuel procurement policy, the maximization of capacity credits and off-  
system margin appears to be an established obligation. As for the symmetry of  
risk and reward, the current incentive mechanism does not fulfill such a criterion.

1 Q. IN DETERMINING WHETHER TO EXTEND THE CURRENT MARGIN  
2 SHARING MECHANISM AND CONTINUE ITS CURRENT APPLICATION,  
3 WHAT FACTORS SHOULD THE COMMISSION CONSIDER?

4 A. Perhaps the most important consideration involves the fact that the gas market,  
5 and specifically the capacity market, has changed over time. As a result, the basic  
6 framework of the Company's sharing incentive has become outdated.

7 After the FERC's restructuring in its Order 636, capacity release and off-  
8 system sales were seen as a mechanism to ameliorate the impact of straight fixed  
9 variable tariff design by allowing secondary market transactions for capacity. As  
10 gas distribution companies made the transition from bundled gas supply, various  
11 state regulatory agencies saw merit in sharing capacity credits in order to  
12 compensate the utilities for increased staffing and to given them an incentive to  
13 participate in the emerging secondary capacity market. As a general rule, early  
14 sharing provisions allowed utilities on average about 20% of the capacity credits  
15 and margins. On this basis, a sharing mechanism was justified and reasonable.

16 However, in the current market environment, significant changes have  
17 occurred. Gas utilities have established the necessary trading expertise, and the  
18 secondary capacity market has become firmly established and vigorous. As such,  
19 a significant portion of the rationale for incentives has been removed.

1           In the current circumstances, with the growing size of the secondary  
2           market, incentives should only be given for superior performance, and there  
3           should be commensurate penalties, or at least no incentives, for average  
4           performance. In the case of the Company, with its seven year history, fairness  
5           would involve a sharing percentage which would be granted above a meaningful  
6           threshold with no sharing for performance below the threshold.

7  
8    Q.    DO YOU HAVE AN ALTERNATIVE INCENTIVE MECHANISM WHICH  
9           YOU RECOMMEND BE ADOPTED BY THE COMMISSION?

10   A.   While there are several variations which might be acceptable, I believe that the  
11          Commission should tailor any incentive plan to the changing operating  
12          characteristics of the utility. Thus, any extension of the Delmarva incentives  
13          should be limited to a specified term. As for the structure, it is recommended that  
14          \$4.379 million of margins (75% of the average historical margin level) be  
15          established as the initial incentive benchmark. For margins in excess of the  
16          benchmark, a 20% sharing could be authorized for the Company. Such a structure  
17          provides ample incentive for better than average performance. It should also be  
18          noted that this incentive structure should provide the Company with about \$0.8  
19          million if it achieves its forecasted margins in 2008-2009. This is a material  
20          ratepayer contribution to the Company and it is a more than adequate reward for

1 the Company to strive to maximize its secondary market transactions, particularly  
2 given the Company's current capacity reserve.  
3

4 Q. SHOULD THE MARGIN SHARING FORMULA FOR SHARING BE  
5 MODIFIED AS PART OF THIS PROCEEDING?

6 A. In my opinion, it should. While it is recognized that such incentives are typically  
7 addressed in base rate proceedings, it is recommended that this practice be  
8 changed. Base rates are not affected by incentives such as margin sharing since  
9 they are typically treated as below the line revenues. In addition, capacity related  
10 margins and credits are typically reviewed as part of GCR proceedings. And  
11 finally, GCR proceedings are where a gas utility's demand requirements and  
12 capacity resources are analyzed. In the current proceeding, Delmarva has added  
13 25,000 Dth of interstate capacity that has a direct impact on the level of capacity  
14 margins and credits it will potentially be able to achieve prospectively. Thus,  
15 GCR reviews, where added capacity costs are put into rates, would be the logical  
16 venue for setting prospective capacity related incentives.  
17

1        - Gas Price Hedging

2  
3    Q.    WHAT ARE THE BASIC PARAMETERS FOR A GAS UTILITY'S HEDGING  
4        PROGRAM?

5    A.    As an initial matter, a hedging program should seek to minimize the effect of gas  
6        price volatility on ratepayers. Hedging should accomplish this by having the  
7        utility's cost of gas, over time, reflect average market prices prevailing over a  
8        twelve to eighteen month period prior to a given month of use. The hedging  
9        should not seek to beat market prices, and it should be designed to cover a utility's  
10       monthly gas purchases rather than forecasted sendout requirements. Thus, the  
11       percentage of gas that is hedged should be essentially the same for both peak and  
12       non-peak months. Such a hedging framework will result in hedge prices that may  
13       be above or below market or indexed prices in any given month, but over time the  
14       hedge positions should equal index prices. It is also important that a utility's  
15       hedging program balance two associated hedging risks. The first risk involves  
16       having no hedge positions during periods of increasing prices. The second risk  
17       involves having hedge positions during periods of decreasing prices. In order to  
18       balance these risks, utilities can follow a program that hedges 50% of its purchases  
19       and leaves the other 50% to be purchased at index rates. With such a balanced  
20       approach, the utility can mitigate gas price increases and yet still benefit from

1 price declines. Hedging that is done on this basis effectively recognize that future  
2 gas prices movements are exogenous. To the degree its utility's program is based  
3 on predictions of future gas prices, its hedging becomes speculative.

4  
5 Q. BASED ON THESE TYPES OF CONSIDERATIONS, WHAT IS YOUR  
6 ASSESSMENT OF DELMARVA'S CURRENT HEDGING PROGRAM?

7 A. At the time Delmarva initiated its hedging program the natural gas market was  
8 beginning a period of rising prices. Over the ensuing period, gas prices increased  
9 from about \$2.00 per Dth up to about \$8.00 per Dth (a 300% increase). Under  
10 these conditions, it is not surprising that hedged positions, for the most part, had  
11 lower average costs than indexed positions. However, it is unlikely that the gas  
12 market will increase another 300% over the next ten years to a level of around \$32  
13 per Dth.

14 Based on this and other hedging considerations, it appears that this is an  
15 appropriate time to reevaluate Delmarva's current hedging program and make  
16 changes as required. In this regard, the Company has stated "Company personnel  
17 on a routine basis discuss various hedging concepts" but "these discussions have  
18 not resulted in a fundamental change in the implementation/execution of the  
19 Company's Gas Hedging Program (Company Response PSC-15). The Company,  
20 however, has also acknowledged that it "has not prepared any analysis . . . that

1 compare the results if different hedging parameters had been used" (Company  
2 Response PSC-16).

3 On Schedule 5, data is presented concerning the Company's hedging since  
4 the second quarter of 2006 and as forecasted through the third quarter of 2009. As  
5 the data shows, the Company's level of hedging, as expressed as a percentage of  
6 estimated requirements, varied materially by period from a low of 24% to a high  
7 of 121%. More significantly, when the Company's resultant hedge positions were  
8 marked to market ("M2M"), the hedge position's prices consistently exceed index  
9 and have effectively added almost \$17 million to commodity gas costs. In  
10 addition, estimates for the next 12 months are currently showing hedge costs that  
11 are an additional \$27 million above index costs.

12  
13 Q. ARE YOU AWARE OF THE COMMISSION'S ORDER NO. 6478 IN DOCKET  
14 NO. 03-378F, AND IF SO, HOW DOES THAT AFFECT YOUR  
15 RECOMMENDATIONS IN THIS PROCEEDING?

16 A. I have recently reviewed both the Commission's Order and the Findings and  
17 Recommendations of the Hearing Examiner in Docket No. 03-378F. In addition, I  
18 would note that I presented testimony on Delmarva's hedging in Docket Nos. 97-  
19 293F, 99-425F and in 03-378F. With this perspective, it appears evident that the  
20 Company's current program needs some revisions. The natural gas pricing levels

1 seen during the past several years indicate that a more balanced approach would  
2 best protect the ratepayers' interests. The results of a highly hedged portfolio have  
3 been evident from the Company's results as shown on Schedule 5.

4 In reviewing the documentation from Docket No. 03-378F, it is clear that  
5 the 70% "hedging target" for the Company was interpreted differently by various  
6 parties. The Company did not view the target as an upper limit and it has  
7 continued to hedge in excess of its purchase requirements. Both Ms. Crane and I  
8 believed that the 70% hedging target, while perhaps not a maximum target, did  
9 delineate a hedging level where the Company had "an additional burden to  
10 demonstrate the reasonableness of its hedging decisions once that target is  
11 exceeded" (Hearing Examiner, Ibid, page 16).

12 Reviewing the data on Schedule 5 shows two relevant facts. First, over the  
13 twelve reported periods, the Company did, in fact, hedge 70% of its total  
14 requirements. However, in five of seven periods when it exceeded 70% hedging,  
15 its prices were higher than market. Second, such performance with a 70% target  
16 requires a detailed explanation and could be cause for questions concerning abuse  
17 of discretion. Unfortunately, the Company chose not to explain its recent  
18 purchasing at about \$44 million above market, nor did it set forth any hedging  
19 modifications to ensure that such results were not repeated in the future.  
20

1 Q. WHAT TYPES OF CHANGES SHOULD BE CONSIDERED BY DELMARVA  
2 AS PART OF ANY REEVALUATION?

3 A. As mentioned previously, the Company should consider lowering its hedge  
4 positions as a percentage of its total gas purchases. It should also evaluate the  
5 division of its hedging into non-discretionary and discretionary portions. The non-  
6 discretionary hedging could be taken on a pro-rated basis with minimum and  
7 maximum parameters. Discretionary hedging would have a percentage ceiling and  
8 would take positions based on market trends.

9 The program should also specify that hedging for any individual month of  
10 use would be taken during the preceding 12 to 18 months. Such a hedging interval  
11 gives the Company some timing flexibility for both its non-discretionary and  
12 discretionary hedge transactions. It would also be useful for the Company to  
13 establish a pre-determined trading range for its hedging. During the past six years,  
14 the average Henry Hub prices have been about \$7.00 per Dth. Conceptually,  
15 hedging could be accelerated when prices were below \$5.50 per Dth and reduced  
16 when prices were above \$8.50 per Dth. Assuming those limits during the past six  
17 years (72 months), there were twelve months below \$5.50 per Dth and eleven  
18 months above \$8.50. This would suggest a relatively normal price curve which  
19 would give the Company guidance for taking its discretionary hedges. Potentially,  
20 a hedging program could require 30% non-discretionary hedging, 20% fully

1 discretionary, and an additional 20% discretionary if prices were below the lower  
2 price limit when the positions were taken.

3  
4 Q. HOW WOULD YOU RECOMMEND THAT THE HEDGING PROGRAM BE  
5 REEVALUATED?

6 A. Two courses of action would appear to be possible. First, the Commission could  
7 require the Company to perform a reevaluation and file its conclusions with the  
8 parties including justification for any proposed new program. Subsequently, the  
9 parties would have an opportunity to file their comments on the Company's  
10 submission. Alternatively, the Company and the parties could address the  
11 reevaluation through a collaborative process. Either of these alternatives should  
12 be able to be completed within six months.

13 In addition, the Company should be required to file its Gas Hedging  
14 Quarterly Reports within 30 days of the end of each quarter. During the past two  
15 years, these reports have been issued between 45 and 75 days after the close of the  
16 quarter. Filing these reports as quickly as possible, perhaps even on a monthly  
17 basis, would allow the parties to better monitor hedging activities on a timely  
18 basis. The Company should also file any internal reports it develops on hedging  
19 that describe its program, explain how and why it takes its positions, and what

1 program changes it has evaluated. If the Company continues to have the latitude  
2 that it currently claims to have, then such reporting is all the more appropriate.

3  
4 - Other Procurement Issues

5  
6 Q. ARE THERE ANY OTHER PROCUREMENT RELATED ISSUES THAT YOU  
7 BELIEVE SHOULD BE ADDRESSED?

8 A. Yes, there are two additional issues that the Commission should consider. The  
9 first involves a pipeline penalty that was incurred by the Company on the  
10 Columbia system in January 2007. The penalty of \$68,150 was for overtaking  
11 3,326 Dth of FSS supply on the 17<sup>th</sup> of the month. The reason for raising the issue  
12 involves both the level of capacity held by the Company and the fact that the  
13 planned and actual temperatures for that day were about 25°F (40 HDD). Under  
14 such conditions, and even at 65 HDD, the Company should not have had a  
15 capacity deficiency. On the basis of the information provided, it is unclear  
16 whether transportation customers who under delivered 2,176 Dth or the Company  
17 that was not able to handle the problem with its balancing resources should be held  
18 responsible for the penalty. However, it is clear that sales customers should not  
19 have to pay the \$68,150 amount.

1           A second issue involves the potential for the Company to utilize a third  
2 party asset manager to optimize the sale of its excess capacity. Experience has  
3 shown that asset managers can frequently obtain greater margins and credits from  
4 capacity transactions than those obtained by the utility itself. This appears to be  
5 the case because the trading platforms maintained by asset managers are far more  
6 robust than those of utilities. When asked whether the Company had evaluated the  
7 potential of using a third party asset manager, the response was:

8           In the last several years, the Company has not evaluated the potential  
9 of using a third party asset manager . . . It has met with asset  
10 managers to discuss the concept but these did not result in any  
11 evaluation or subsequent action (Company Response PSC-20).  
12

13  
14           Based on the Company's response, it is suggested that it contact various  
15 asset managers to determine their interest in managing Delmarva's portfolio. If  
16 there were sufficient interest, the Company could then solicit bids to determine  
17 what margins and credits could be obtained. If the subsequent bids were not  
18 materially better, then the Company could simply choose not to go any further  
19 with such contracting.  
20  
21

LeLash/Direct

1 Q. MR. LELASH, DOES THIS CONCLUDE YOUR DIRECT TESTIMONY IN

2 THIS MATTER?

3 A. Yes, it does.

LeLash/Direct

V. SUPPORTING SCHEDULES

LeLash/Direct

Schedule 1

Delmarva Power & Light Company  
Henry Hub - Dollars per Dth

	<u>2005</u>	<u>2006</u>	<u>2007</u>	<u>2008</u>	<u>2009 A/F</u>
January	\$ 6.18	\$ 8.73	\$ 6.40	\$ 7.97	\$ 5.20
February	6.11	7.54	8.04	8.49	4.50
March	6.94	6.89	7.11	9.36	4.10
April	7.16	7.07	7.58	10.15	4.00
May	6.46	6.21	7.64	11.25	3.80
June	7.19	6.26	7.34	12.67	3.80
July	7.60	6.12	6.22	11.19	4.00
August	9.47	7.17	6.27	8.26	3.80
September	12.41	4.86	5.99	7.69	3.30
October	13.59	5.75	6.72	6.72	4.00
November	10.28	7.38	7.01	6.59	5.00
December	12.90	6.74	7.11	5.76	5.30
Average	\$ 8.86	\$ 6.73	\$ 6.95	\$ 8.84	\$ 4.23

SOURCE: PIRA North American Gas Forecast Monthly, January 27, 2009, page 18.

LeLash/Direct

Schedule 2  
Page 1 of 2

Delmarva Power & Light Company  
Design Day Deliverability  
(Mcf)

	<u>Actual</u>		<u>Potential</u>
<u>Pipeline</u>			
Transco Sentinel FT	24,155		24,155
Transco FT	55,356		55,356
Columbia FTS	26,009		26,009
Tetco ITP	9,662		9,662
Canadian	2,705		2,705
Transco PS3	1,600		1,600
<u>Delivered Storage</u>			
Transco GSS	28,420		28,420
Columbia FSS	15,458		15,458
Transco LNG	2,840		2,840
Penn York SS-2	2,180		2,180
Delmarva LNG	<u>25,000</u>	<u>20,000</u>	<u>45,000</u>
Total Deliverability	193,385	20,000	213,385
Total Firm Requirements	178,169		178,169
Capacity Reserve %	109%		120%

SOURCE: October 2008 Strategic Gas Supply Plan, Figures 2 and 8.

LeLash/Direct

Schedule 2  
Page 2 of 2

Delmarva Power & Light Company  
Customer and Cost Increases

<u>Period</u>	<u>RSH Customers</u>		<u>Total Customers</u>		<u>Fixed Costs</u>	
		<u>% Change</u>		<u>% Change</u>	<u>(000's)</u>	<u>% Change</u>
2003-2004	95,902	- %	117,263	- %	\$18,944	- %
2004-2005	97,535	1.7	118,665	1.2	18,094	(4.5)
2005-2006	99,161	1.7	120,242	1.3	17,917	(1.0)
2006-2007	100,496	1.3	121,450	1.0	20,748	15.8
2007-2008	101,217	0.7	121,947	0.4	22,869	10.2
2008-2009	-	-	-	-	25,653	12.2

SOURCES: Company Responses DPA-15 and DPA-17.

LeLash/Direct

Schedule 3

Delmarva Power & Light Company  
2004-2008 Inventory Levels  
(Dth)

	<u>ESS</u>	<u>GSS</u>	<u>SS-2</u>	<u>FSS</u>	<u>LNG</u>	<u>Total</u>
Highest Storage Level	264,466	2,041,036	340,560	960,327	235,437	3,841,826
November, 2004	112,473	1,949,038	290,224	891,902	225,937	3,469,574
% of Highest	43	95	85	93	96	90
October/November 2005	112,458	2,041,036	330,954	960,327	223,418	3,668,193
% of Highest	43	100	97	100	95	95
October/November 2006	112,473	1,975,075	340,560	934,899	206,172	3,569,179
% of Highest	43	97	100	97	88	93
October/November 2007	264,446	1,984,807	340,560	936,608	219,494	3,745,915
% of Highest	100	97	100	98	93	98
October 2008	264,466	1,561,273	340,560	769,757	151,457	3,087,513
% of Highest	100	76	100	80	64	80

SOURCE: Company Response PSC-28.

LeLash/Direct

Schedule 4

Delmarva Power & Light Company  
Off-System Margins and Capacity Release Credits  
(\$000's)

<u>Period</u>	<u>Off-System</u>	<u>Releases</u>	<u>Total</u>
2001-2002	\$2,216	\$1,678	\$3,894
2002-2003	1,513	2,837	4,350
2003-2004	3,050	44	3,094
2004-2005	4,634	3,433	8,067
2005-2006	1,616	4,108	5,724
2006-2007	2,207	5,919	8,126
2007-2008	<u>2,207</u>	<u>5,408</u>	<u>7,615</u>
Average	\$2,492	\$3,347	\$5,839
2008-2009 (Estimated)	\$1,920	\$6,500	\$8,420

SOURCES: Company Response PSC-75, Crane Testimony (Docket No. 06-285F) page 16,  
and Schedule CRM-2.

## LeLash/Direct

Schedule 5

**Delmarva Power & Light Company**  
**Gas Hedging Summary**  
 (000's)

<u>Period</u>	<u>Requirements</u>	<u>Hedged</u>	<u>Hedge %</u>	<u>M2M</u>
2Q 2006	3,540	1,165	33%	\$ (1,898)
3Q	2,671	635	24	(1,473)
4Q	3,682	4,260	116	(4,461)
1Q 2007	5,372	4,128	77	(7,599)
2Q	3,669	2,828	77	254
3Q	2,031	2,453	121	(2,586)
4Q	3,908	3,650	93	(2,621)
1Q 2008	5,092	3,258	64	(715)
2Q	3,895	1,140	29	2,715
3Q	<u>2,770</u>	<u>1,405</u>	<u>51</u>	1,497
Totals - Actual	36,630	24,922	68%	\$ (16,887)
Oct. 2008 - Mar. 2009	9,167	7,883	86%	\$ (15,243)
2Q & 3Q 2009	<u>6,420</u>	<u>3,950</u>	<u>62%</u>	<u>(11,868)</u>
Totals - Estimated	<u>15,587</u>	<u>11,833</u>	<u>76%</u>	<u>\$ (27,111)</u>
Totals	52,217	36,755	70%	\$ (43,998)

SOURCES: Gas Hedging Quarterly Reports, March 2007 and July and September 2008.

LeLash/Direct

Schedule 6

Delmarva Power & Light Company  
Timing of Hedge Positions  
(000's)

<u>Hedge Date</u>	<u>Month of Use</u>				<u>Mar.2008</u>	<u>Totals</u>
	<u>Nov.2007</u>	<u>Dec.2007</u>	<u>Jan.2008</u>	<u>Feb.2008</u>		
December 2006	150	155	155	145	155	760
January 2007	-	-	-	-	-	-
February	-	-	-	-	-	-
March	-	-	-	-	-	-
April	150	155	-	-	-	305
May	75	77	77	72	77	378
June	75	78	78	73	78	382
July	300	155	155	145	155	910
August	450	465	310	435	310	1,970
September	-	-	-	-	-	-
October	150	155	155	145	155	760
November	-	70	-	-	-	70
December	-	138	310	73	-	521
Totals	1,350	1,448	1,240	1,088	930	6,056

SOURCE: Company Response PSC-83.

## LeLash/Direct

Schedule 7Delmarva Power & Light Company  
Monthly Percentages of Hedges  
(000's)

<u>Hedge Date</u>	<u>Hedges</u>	<u>% of Total</u>
December 2006	760	12.6%
January 2007	-	-
February	-	-
March	-	-
April	305	5.0
May	378	6.2
June	382	6.3
July	910	15.0
August	1,970	32.5
September	-	-
October	760	12.6
November	70	1.2
December	<u>521</u>	<u>8.6</u>
Totals	6,056	100.0%

SOURCES: Company Response PSC-83.

LeLash/Direct

VI. APPENDIX: PRIOR R.W. LELASH TESTIMONIES

**R. W. LELASH'S REGULATORY TESTIMONIES**  
**(2003 to Present)**

262. Rhode Island, New England Gas Company (Docket No. 3476) Service Quality Surrebuttal Testimony for the Division of Public Utilities (February, 2003).
263. Pennsylvania, Philadelphia Gas Works (Docket No. R-00038173) Gas Procurement and Policy Testimony for the Pennsylvania Office of Consumer Advocate (April, 2003).
264. New Jersey, Elizabethtown Gas Company (Docket No. GA02020099) Comments Concerning Affiliate Audit for the New Jersey Division of the Ratepayer Advocate (June, 2003).
265. Maine, Northern Utilities (Docket No. 2002-140) Management Audit and Service Quality Report for the Maine Public Utilities Commission (June, 2003).
266. New Jersey, Public Service Electric & Gas Company (Docket No. GR03050400) Pipeline Refund Allocation Testimony for the New Jersey Division of the Ratepayer Advocate (August, 2003).
267. Ohio, Vectren Energy Delivery of Ohio (Case No. 02-220-GA-GCR) Gas Procurement and Policy Testimony for the Ohio Consumers' Counsel (November, 2003).
268. Delaware, Delmarva Power & Light Company (Docket No. 03-378F) Evaluation of Gas Procurement and Price Hedging Testimony for the Delaware Public Service Commission (February, 2004).
269. Pennsylvania, Philadelphia Gas Works (Docket Nos. R-00049157 and P-00042090) Purchased Gas Cost Testimony for the Pennsylvania Office of Consumer Advocate (May, 2004)
270. Pennsylvania, Philadelphia Gas Works (Docket Nos. R-00049157 and P-00042090) Purchased Gas Cost Rebuttal Testimony for the Pennsylvania Office of Consumer Advocate (May, 2004)
271. Delaware, Chesapeake Utilities Corporation (Docket No. 02-287F) Gas Supply Plan Review for Chesapeake Utilities and the Delaware Public Service Commission (July, 2004).
272. Georgia, Atmos Energy Corporation (Docket No. 18509-U) Procurement and Capacity Plan Testimony for the Georgia Public Service Commission (August, 2004).
273. Georgia, Atlanta Gas Light Company (Docket Nos. 18437-U and 8516-U) Procurement and Capacity Plan Testimony for the Georgia Public Service Commission (August, 2004).
274. New Jersey, NUI Utilities and AGL Resources ( Docket No. GM04070721) Terms and Conditions of Merger Testimony for the New Jersey Ratepayer Advocate (September, 2004).
275. Georgia, Atlanta Gas Light Company (Docket No. 18638-U) Business Risk Testimony for the Georgia Public Service Commission (February, 2005).
276. Pennsylvania, Philadelphia Gas Works (Docket No. R-00050264) Purchase Gas Cost Testimony for the Pennsylvania Office of Consumer Advocate (April, 2005).
277. Federal Energy Regulatory Commission, Exelon and Public Service Enterprise Group (Docket No. EC05-43-000) Market Power Testimony by Affidavits for the New Jersey Division of the Ratepayer Advocate (April and May, 2005).

278. Pennsylvania, PECO Energy Company (Docket No. R-00050537) Gas Procurement and Policy Testimony for the Pennsylvania Office of Consumer Advocate (July, 2005).
279. Georgia, Atmos Energy Corporation (Docket No. 20528-U) Gas Supply Plan Testimony for the Georgia Public Service Commission (August, 2005).
280. New Jersey, Public Service Electric & Gas/Exelon (Docket No. EM05020106) Gas Related Merger Testimony for the New Jersey Ratepayer Advocate (November, 2005).
281. New Jersey, Public Service Electric & Gas/Exelon (Docket No. EM05020106) Gas Related Merger Surrebuttal Testimony for the New Jersey Ratepayer Advocate (December, 2005).
282. New Jersey, Pivotal Utilities Holdings (Docket No. GR05040371) Pipeline Replacement Cost Recovery Testimony for the New Jersey Ratepayer Advocate (February, 2006).
283. New Jersey, Public Service Electric & Gas Company (Docket No. GR05050470) Gas Supply Requirements Testimony for the New Jersey Ratepayer Advocate (May, 2006).
284. New Jersey, Public Service Electric & Gas Company (Docket No. GR05100845) Base Rate Gas Policy Testimony for the New Jersey Ratepayer Advocate (June, 2006).
285. Vermont, Vermont Gas Systems (Docket No. 7109/7160) Report on Gas Price Hedging for Vermont Gas Systems (December, 2006).
286. Delaware, Chesapeake Utilities Corporation (Docket No. 06-287F) Report on Gas Price Hedging for Chesapeake Utilities Corporation (March 2007).
287. Delaware, Chesapeake Utilities Corporation (Docket No. 06-287F) Gas Procurement and Policy Testimony for the Delaware Public Service Commission (March, 2007).
288. Pennsylvania, Philadelphia Gas Works (Docket No. R-00061931) Base Rate Case Testimony for the Pennsylvania Office of Consumer Advocate (April, 2007).
289. Pennsylvania, Philadelphia Gas Works (Docket No. R-00072110) Gas Cost Rate Testimony for the Pennsylvania Office of Consumer Advocate (April 2007)
290. Pennsylvania, Philadelphia Gas Works (Docket No. R-00061931) Base Rate Rebuttal Testimony for the Pennsylvania Office of Consumer Advocate (May 2007).
291. Pennsylvania, Philadelphia Gas Works (Docket No. R-0001931) Base Rate Surrebuttal Testimony for the Pennsylvania Office of Consumer Advocate (May 2007).
292. Pennsylvania, PECO Energy Company (Docket No. R-00072331) Gas Procurement and Policy Testimony for the Pennsylvania Office of Consumer Advocate (July, 2007).
293. Georgia, Atlanta Gas Light Company (Docket No. 18437-U) Capacity Supply Plan Testimony for the Georgia Public Service Commission (August, 2007)

294. Delaware, Chesapeake Utilities Corporation (Docket No. 07-186) Gas Policy Testimony for the Delaware Public Service Commission (December, 2007).
295. Delaware, Chesapeake Utilities Corporation (Docket No. 07-246F) Gas Procurement and Policy Testimony for the Delaware Public Service Commission (April, 2008).
296. Pennsylvania, Philadelphia Gas Works (Docket No. R-2008-2021348) Gas Cost Rate Testimony for the Pennsylvania Office of Consumer Advocate (April, 2008).
297. New Jersey, New Jersey Natural Gas Company (Docket No. GR07110889) Base Rate Policy Testimony for the Division of Rate Counsel (April, 2008).
298. Georgia, Atmos Energy Corporation (Docket No. 27168) Gas Supply Plan Testimony for the Georgia Public Service Commission (August, 2008).
299. Pennsylvania, Philadelphia Gas Works (Docket No. R-2008-2073938) Emergency Rate Relief Testimony for the Pennsylvania Office of Consumer Advocate (December, 2008).